Evaluation of Operating Procedures in Carbon TerraVault's Monterey Formation 26R Permit Application

This evaluation for the proposed Carbon TerraVault (CTV)-Elk Hills 26R Class VI geologic sequestration project summarizes EPA's review of proposed operating procedures for four injection wells—the existing 373-35R well and three currently unnamed wells to be constructed—per 40 CFR 146.82(a)(7),(9),(10) and 146.88. CTV submitted information regarding well operation in their Class VI permit application narrative dated November 5, 2021. This review identifies preliminary questions and includes requests for supplemental information from the applicant.

The proposed operational procedures (which appear to be specific to Well 373-35R) are described on pages 37-38 of the Narrative and summarized in Table 8, which is replicated below:

Table 8 of the Narrative		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	2,300	Psig
Downhole	4,900	Psig
Average Injection Pressure	Average over time	
Surface	1,375	Psig
Downhole	3,699	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	15-25 per well	Mmscfd
Maximum Injection Volume and/or Mass	38 Million	Tonnes
Average Injection Volume and/or Mass	38 Million	Tonnes
Annulus Pressure	2,984 @ packer	Psig
Annulus Pressure/Tubing Differential	715 @packer @ average injection condition	Psig

Injection Pressure

The basis for the proposed maximum allowable injection pressure (MAIP) is described in Attachment B – the AoR and Corrective Action Plan (AoR CA). CTV states that the MAIP will be below 90% of the fracture pressure of the Monterey Formation at the base of the Reef Ridge Shale confining zone, and is calculated as follows:

$$7{,}031\,psi \times 0.9 = 6{,}327.9\,psi$$

Where:

Fracture pressure (Fp) at base of confining zone = 7,031 psi

Safety factor = 0.9 (90%)

Tables 6 and 7 of the AoR CA provide fracture gradients and fracture pressures for the Monterey Formation 26R reservoir, and are replicated below:

Table 6 (of AoR CA)		
Interval	**Breakdown Fracture Gradient psi/ft**	**Fracture Pressure (psi) at base of Reef Ridge Shale (6,826.6 ft TVD)**
Monterey Formation 26R	1.03	7,031

Table 7 (of AoR CA)	
Injection Pressure Details	**Injection Well 1 373-35R**
Breakdown fracture gradient (psi/ft)	1.03
Maximum injection pressure (90% of fracture pressure) (psi)	6,327.9
Elevation corresponding to maximum injection pressure (ft MSL)	6,826.6
Elevation at the top of the perforated interval (ft MSL)	-5,484
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,031
Planned maximum injection pressure / gradient (top of perforations)	4,900 / 0.71

The calculated maximum injection pressure listed in Table 7 of the AoR CA for injection well 373-35R does not appear to be correct. It is listed in Table 7 as 7,031 psi, which is the fracture pressure of the Monterey 26R Formation at the base of the Reef Ridge Shale. CTV proposes to operate at an injection pressure of 3,699 to 4,900 psi, well below 90% of the injection zone fracture pressure. However, the proposed injection pressures will need to be confirmed as being below 90% of the fracture pressure at the top of the perforations (i.e., within the Monterey Formation injection zone), and the discrepancy in maximum injection pressures will need to be resolved. (See the evaluation of the AoR CA for questions about the perforation depths in Tables 5 and 7.)

While it is acknowledged that specific information about the three proposed wells has not been determined, operating conditions specific to the depth and perforations in those wells will need to be provided before injection may be authorized. For purposes of preparing a Class VI permit to construct, CTV should provide estimates.

CTV states in the AoR CA that their final/maximum values for surface and downhole injection pressures are below those associated with current Class II UIC permits which include a fracture gradient of 0.80 psi/ft. It appears that CTV conducted a test(s) to obtain a higher fracture gradient, 1.03 psi/ft, as seen in Table 6 of the AoR CA, above. However, these tests are not described in the application and will need to be provided for validation of the fracture pressure of the injection and confining zones and the corresponding maximum injection pressures. A question for the applicant regarding this topic is included in the AoR CA Evaluation.

Questions/Requests for the applicant:

- *Please provide separate stand-alone versions of the description of well operations in Attachment A for Well 373-35R and each of the three planned injection wells that describe operating conditions that are specific to the construction/perforation depths in each well. The attachments should include the following: injection well operating conditions (e.g., a tabular description of surface and bottomhole maximum injection pressures, annulus pressure, annulus pressure/tubing differential, and the maximum CO_2 injection rate); how the maximum injection pressure was determined; a description of routine shutdown procedures; and tables summarizing reporting of well and project-related monitoring.*
- *Attachment E (the PISC and Site Closure Plan), page 1 states that the Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. Please clarify that injection limits (e.g., pressures) will be based on the fracture pressure of the Monterey Formation 26R injection zone (i.e., at the tops of the perforations).*
- *Please provide the fracture pressure (psi) at the top of the perforations in injection well 373-35R within the Monterey Formation (and not the base of the Reef Ridge Shale) and confirm the proposed maximum injection pressure does not exceed 90% of this value, per 40 CFR 146.88(a).*
- *Please show the conversion of the average injection rate from million standard cubic feet per day (mmscfpd; Table 8 of the Narrative) to tonnes per day (t/day; Table 5 of the AoR CA). Also, please ensure these values are equal and are consistent throughout the permit application.*

Annulus Pressure and Annulus/Tubing Pressure Differential

Regarding Well 373-35R and in Table 8 of the Narrative excerpted above, the annulus pressure/tubing differential is 715 psi at the packer at the average injection pressure of 3,699 psi, resulting in a 2,984 psi annulus pressure at the packer. Table 8 defines the 2,984 psi annulus pressure as a proposed limit or permitted value, however this pressure occurs at the average injection pressure of 3,699 psi. Clarification is needed to ensure that the 2,984 psi annulus pressure at the packer is indeed a proposed maximum limit and corresponds to a maximum injection pressure. Additionally, the applicant does not include the surface pressure of the casing-tubing annulus for injection well 373-35R during injection operations. The applicant will need to confirm that the 2,984 psi annulus pressure at the packer is within a specified annular pressure range at the surface. If the above is confirmed, the annulus pressure of 2,984 psi at the packer is well below the tubing and packer burst strengths of 10,480 psi and 7,500 psi respectively, as noted in Table 7 of Attachment A, which is excerpted below. As noted above, this information will also need to be provided for each of the three proposed wells.

Casing specifications for Well 373-35R (Table 6 of Attachment A)

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	53	24	0.25	20	H40	52
Surface	331	17.5	0.33	13.375	H40	48
Intermediate	3,006	12.25	0.395	9.625	K-55	40
Long String	7,988	8.75	6.276 6.276 6.366	7.0	N-80 K-55 K-55	26 26 23

Tubing specifications for Well 373-35R (Table 7 of Attachment A)

Component	Setting Depth (ft)	Min Yield Strength (psi)	Burst Pressure (psi)	Collapse Pressure (psi)	Material
Tubing	7,043	80,000	10,480	11,080	13CR L-80
Packer	7,049	80,000	7,500	7,500	13CR L-80 or other CRA

Questions/Requests for the applicant:

- *Please clarify that a 2,984 psi annulus pressure at the packer is the proposed maximum limit and that it corresponds with the maximum injection pressure for Well 373-35R. Additionally, please specify the surface annular pressure range that equates to a 2,984 psi annulus pressure at the packer.*
- *There appears to be a typo resulting in the packer depth being greater than the tubing depth in Table 7 of the AoR CA. Please revise Table 7 to include the correct packer depth.*

Maximum CO_2 Injection Rate

The applicant proposes a daily CO_2 injection rate of 993 tons per day, which equates to 362,445 tons/year (or a maximum 9.4 million tons over the planned 26-year injection phase of the project, assuming continuous operation (i.e., 365 days/year) of all four injection wells at the same rate) as seen in Table 5 of the AoR CA and excerpted below. This is consistent with the permit application narrative, which states that CTV plans to store up to 1.46 million tonnes of CO_2 annually in the 26R Monterey Formation; that equates to 4,000 tons/day via the four injection wells. Based on the injection duration and injection rate listed in Table 5, the proposed CO_2 volume is appropriate and less than the 38 million tonne storage capacity of the injection zone described in the Narrative. However, the planned start of injection operations in Table 5 (year 2044) does not correspond to the start of injection operations discussed in the Narrative (year 2025).

Table 5 (of AoR CA). Operating details.

Operating Information	Injection Well 1 373-35R
Location (global coordinates) X Y	 35°16'34.5276"N 119°28'24.1836"W
Model coordinates (ft) X Y	 6,121,906 2,290,081
No. of perforated intervals	13
Perforated interval (ft MSL) Z top Z bottom	 -5,484 -6,289
Wellbore diameter (in.)	7
Planned injection period Start End	 2044 2070
Injection duration (years)	26
Injection rate (t/day)*	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

In the Testing and Monitoring Plan (pg. 5), CTV states that the volume of CO_2 injected into the Monterey Formation 26R Sands will be calculated from the injection flow rate and CO_2 density, and that density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator (https://sequestration.mit.edu/tools/index.html). However, it appears that the online calculator is no longer operational.

Questions/Requests for the Applicant:

- *Please include a description of standard operating procedures to ensure that the maximum daily injection rate will not be exceeded.*

- *Please update Table 5 or the permit application narrative to reflect the correct planned injection start and end dates.*
- *The Massachusetts Institute of Technology's CO_2 Thermophysical Calculator is no longer operational. Please revise the methodology by which the CO_2 density will be calculated.*

Shutdown Procedures

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the shutdown plan will be initiated in response to multiple risk scenarios, including well integrity failure, monitoring equipment failure, natural disasters, USDW contamination, CO_2 leakage, and seismic events. The Plan defines "initiating the shutdown plan" as immediately ceasing injection. It also states (on pg. 1) that "gradual cessation of injection" may be appropriate in certain circumstances if approved by the UIC Program Director. However, the application does not describe procedures for gradually shutting down the well, either for routine workovers or in response to emergency events (other than those that warrant an immediate shutdown). Documenting such procedures will ensure that procedures are in place to shut down the well in a manner that will not damage the well and cause a mechanical integrity issue.

Questions/Requests for the applicant:

- *Please describe the procedures for "gradual cessation of injection," i.e., the rate of injection volume reduction over a specified number of days.*
- *Please also describe routine well shutdown procedures (e.g., for well workovers), and if these would be the same as the gradual shutdown procedures discussed above.*

Automated Shutdown System

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the automatic shutdown devices will be activated if wellhead pressure exceeds the specified shutdown pressure listed in the permit, or if the annulus pressure indicates a loss of external or internal well containment (pg. 3). However, standard operating procedures that support the automated shutdown system are not provided.

Questions/Requests for the applicant:

- *Please include standard operating procedures to support the automated shutdown system.*

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
    - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
    - *Step-by-step procedures that would be employed during stimulation.*